2.2.3.1 Combustion Turbine - Generator

The plant configuration is based on a Siemens Westinghouse 501 F combustion turbine (or equivalent[1]) in a 1 x 1 configuration (single combustion turbine and single steam turbine). The combustion turbine is a turbine engine in which natural gas is introduced to air that has been compressed to a high temperature and pressure. The fuel/air mixture is ignited, and the expanding gas drives the turbine. The turbine's rotating shaft is coupled to an electric generator that produces electricity. The hot gases escaping from the turbine exhaust are ducted to the heat recovery steam generator (HRSG), where additional useful energy is extracted.

At 54° F ambient temperature, the combustion turbine would consume 1,653.9 million British thermal units (Btu) of natural gas per hour lower heating value (LHV). The required natural gas pressure range at the combustion turbine inlet is 450 to 475 pounds per square inch gauge (psig).

Air/fuel combustion within the turbine would be controlled to minimize flame temperature, which then reduces the formation of nitrogen oxide (NO_x)

Combustion byproducts in the plant's air emissions would be reduced using emission controls that meet or exceed Best Available Control Technology (BACT) as required by regulation.

The combustion turbine configuration would include available noise reduction equipment, including baffling, silencers, and a noise-attenuated enclosure. The entire combustion turbine would be located within a turbine building. This building would have a maximum height of approximately 50 feet above grade.

2.2.3.2 Heat Recovery Steam Generator

Hot exhaust gas that has a temperature of approximately 1,100° F would leave the combustion turbine and flow into the HRSG. The gas temperature can be increased to 1,400° F by firing a natural gas burner[2] (duct burner) located in the HRSG. Duct firing is activated to increase steam supply to the steam turbine, thereby increasing electrical generation.

The HRSG would extract heat from the combustion turbine exhaust gases and generate steam at three pressure levels[3]. The cooled turbine exhaust gas would leave the HRSG at approximately 200° F and be exhausted from the PGF power plant from a 150-foot-high stack. A stack damper would be provided to retain heat during shutdown.

To avoid damage from overheating, the HRSG must generate steam whenever the combustion turbine is in operation. The steam piping system would include a steam turbine bypass to dump

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[1] Specification of plant output, emissions, and other operating parameters have all been based on the use of the Seimens 501 F class turbine. Turbines from other vendors, such as General Electric, would be considered in final equipment selection. "Or equivalent" means that the selection of an alternative turbine would only be made if it would not increase emissions, water consumption, or other environmental parameters that could increase the environmental effects of the plant.

[2] When in use, duct firing consumes approximately 326 million Btu (LHV) per hour.

[3] High-pressure = 700,000 + pounds per hour of steam at 2,250 pounds per square inch absolute (psia) and 1,020° F; intermediate pressure = 400 psia and 1020° F, and low pressure = 58 psia to the low pressure turbine.

steam directly from the HRSG into the condenser system. The bypass system would also be used during startup to warm the steam piping before introducing steam to the steam turbine. The bypass system would come into operation whenever the steam turbine trips and shuts down.

The HRSG would be fully equipped for outside installation without an enclosure. Stairways, platforms, and ladders would be provided as required for operations and maintenance. The stack would be equipped with an emission testing platform and required access. All platforms, stairways, and ladders would meet Occupational Safety and Health Administration (OSHA) requirements. The primary structure of the HRSG would be approximately 70.5 feet high. The exhaust stack associated with the HRSG would be 150 feet high.

The HRSG would be equipped with safety relief valves, as required by the American Society of Mechanical Engineers (ASME) codes for boilers and pressure vessels to avoid over pressuring the various sections of the HRSG. Relief valve outlets would be equipped with silencers to control noise.

The HRSG would also include noise abatement measures to reduce noise levels to 65 to 67 a-weighted decibels (dBA) at 100 feet. These measures would include increasing the thickness of the HRSG walls to approximately 5/8 to 7/8 inches, depending on the HRSG section, and the installation of silencers and noise baffles.

2.2.3.3 Air Emissions Control Systems

Several regulated air pollutants are formed during the combustion of natural gas in the combustion turbine and duct burners. Several types of emission control equipment would be used to minimize emissions of regulated pollutants.

Within the combustion turbine, specially designed burners (low-NO_x burners) would be used to minimize the initial formation of oxides of nitrogen (NO_x) in the turbine exhaust gas.

Emission control equipment, which must be operated within a specific gas temperature range (approximately 600 to 800° F), would be installed in the HRSG to reduce the quantity of regulated pollutants emitted by the power plant. This emissions control equipment would include selective catalytic reduction (SCR) to remove NO_x in the exhaust gas from the combustion turbine and duct burner. The SCR, in combination with the combustion turbine low NOx burners, are the BACT for limiting NO_x emissions.

The SCR would reduce NO_x by spraying an aqueous ammonia mist into the hot exhaust gas stream in the presence of a catalyst that is mounted on a frame in the HRSG. The ammonia breaks down the NO_x in the presence of the catalyst. NO_x emissions would be approximately 2 parts per million (ppm), representing a removal of approximately 92 percent of the NO_x initially formed during combustion.

Carbon monoxide (CO) emissions from combustion would be reduced with the use of an oxidation catalyst, which would also be mounted on a frame within the HRSG. The CO catalyst is expected to reduce CO emissions to approximately 2 ppm. The frames holding both the SCR catalyst and the CO catalyst must periodically be replaced.

Aqueous ammonia[4] for operation of the SCR would be supplied from a 20,000-gallon storage tank. The tank would be sized to hold an 8-day supply of aqueous ammonia. A truck unloading station and the storage tank would be within a containment so that if any of the solution is spilled during unloading operations, or if an accidental release from the tank occurs, it would be readily controlled and cleaned up. The containment would be sized to hold the entire contents of the tank.

A continuous emission monitoring (CEM) system would be provided to monitor stack emissions.

2.2.3.4 Steam Turbine

The steam turbine is a three section reheat/condensing design and would be located in the turbine building along with the combustion turbine. Steam would be initially injected into the high-pressure section of the turbine. After driving the turbine, the cooled steam would be returned to the HRSG and reheated. After reheating, the steam would flow to the reheat steam turbine (intermediate pressure) inlet, adding further drive energy to the turbine. Finally, additional low-pressure steam would be introduced into the low-pressure turbine section to obtain the final drive energy. Spent steam would exhaust to the condensing system.

The steam turbine would be equipped with operating safety equipment to shut off steam supply whenever abnormal operating conditions exist. Control valves would be modulated to control turbine load during normal operation.

2.2.3.5 Electric Generators

The PGF would have two separate electric generators: one driven by the combustion turbine and the other by the steam turbine.

Transmission would be at 500-kV or 230-kV, depending on the BPA transmission line to which the PGF connects. Generator buses would connect the generators to their respective transformers, which would step up the generator voltage to 500,000 (or 230,000) volts. The high-voltage side of the generators would be interconnected in the substation. A generator breaker would allow isolation of the generator from the rest of the electrical system. A generator control system would ensure that breaker closing and tripping are as designed.

The generators would be enclosed, air-cooled units that would run at 3,600 revolutions per minute (RPM)/60 hertz and generate electricity at 18 kV three phase/60 hertz. The generators would be cooled by air circulating through the generator cooling passages. Hot air from the generator cooling would be cooled in water-cooled heat exchangers.

2.2.3.6 Steam Condensing System

Exhaust steam from the steam turbine would be sent to the condensing system to be condensed, and returned as feedwater to the HRSG, where it would be recycled back into steam. Steam

[4] A solution of 81 percent water, 19 percent ammonia.

would be condensed using two condensing/cooling technologies, which would operate in parallel and most efficiently dissipate waste heat over the range of air temperatures that are expected to occur at the plant site. The two cooling systems are (1) an ACC and (2) a wet condenser/wet cooling tower.

The amount of exhaust steam condensed in each portion of the system would be dictated by ambient air temperature. During the winter (when the ACC removes heat most efficiently), the ACC would condense a larger portion of the steam. During hot summer hours (when the ACC is much less effective), the wet condenser/wet tower would condense most of the steam. Only the wet tower would use the evaporative loss of water to transfer heat to the atmosphere. Thus, the use of the parallel system would minimize consumptive water use for cooling. The reduction of water use would be greatest in the winter, when the ACC would serve the greatest portion of the cooling load. At temperatures below 25° F, the wet part of the system would shut down and all condensing would occur through the ACC. The wet part of the system would operate as a topping system to the ACC portion of the condensing system. The wet system operation would increase as ambient temperatures increase.

The wet condenser would be located inside the turbine building at the steam turbine exhaust. The ACC would be located outside the turbine building and connected to the steam turbine by a steam exhaust duct. The wet tower would also be outside of the turbine building and connected to the wet condenser with circulating cooling water piping.

As previously described, the steam piping system would include a steam turbine bypass to dump steam directly from the HRSG into the condenser system.

2.2.3.6.1 Air-Cooled Condenser

The ACC would consist of banks of finned tubes through which the exhaust steam flows. The tubes would be mounted in the ACC to facilitate high-volume air flow around the tubes for cooling and dissipating heat. The air flow would be provided by large motor-driven fans. Heat would be transferred from the steam to the tubes and fins and then removed by the air flowing past the fins. As the steam is cooled, it would condense. The condensate (water) would flow back into collecting areas, from which it would be returned to the HRSG. Because the ACC dissipates heat to the atmosphere, it would be effective when ambient air temperatures are low.[5]

The ACC would be a structure approximately 88 feet high.

[5] The combined condenser system is required to provide adequate cooling while limiting water use. The wet condenser would augment condenser cooling when ambient air temperatures are over 25°F, too high for the air-cooled condenser to provide all the required cooling. Wet condenser use would commence at 25°F and increase until full flow is reached. At ambient temperatures above 65°F, the condenser pressure would gradually increase due to declining performance of the air-cooled condenser and the inability of the wet tower to cool the wet condenser. The resulting condenser back pressure increase would reduce the steam turbine capacity and efficiency.

2.2.3.6.2 Cooling Tower/Circulating Water

The wet condenser would consist of a shell and tube heat exchanger. Cooling water would circulate through the tubes, where it would pick up heat from the condensing steam. The circulating water would cool the steam and condense it on the outside surfaces of the circulating water tubes. The cooling water is then circulated to the wet tower, where it would be cooled and then recycled back to the condenser.

The circulating cooling water would be cooled in the evaporative (wet) cooling tower. The wet cooling tower would be a multi-cell, mechanically-induced draft counter flow unit. Circulated water would be sprayed into the upper stage of the cooling tower and pass through a mechanically induced air flow. The cooling tower would remove the heat absorbed by the circulating water in the condenser and transfer it to the atmosphere through evaporation of some of the circulating water.

The evaporated water would be replaced by the cooling tower makeup. Water use would be minimized by recycling plant process drains to the cooling tower. Water use would be a maximum of 1,100 acre feet per year. Actual water use would vary with ambient air temperatures and plant output.

The cooling tower would be sized to complement the air-cooled portion of the condensing system. The cooling tower cells, basin, distribution piping, and circulating pump sump would be arranged to permit one cell to be removed from service for maintenance and repair without disrupting operation of other cells. All cooling tower cells would be provided with fire protection sprinkler heads or spray nozzles.

The cooling tower circulating water would be exposed to the atmosphere, thus offering the opportunity for organic contamination. Sodium hypochloride (a household bleach) would be added in small quantities to the circulating water to suppress the formation of organic material.

Evaporative losses in the circulating water would lead to increased concentrations of solids, which are drawn off from the circulating water as blowdown. Anti-scaling and anti-corrosion chemicals would be added to the circulating water to suppress scaling and corrosion. All materials are environmentally benign and contain no toxins or metals. Chemical addition would be metered to match demand. The chemicals would be consumed (reacted) while in the wet tower and not leave the tower with the blowdown. Blowdown would be discharged into the facility wastewater system.

A manually controlled blowdown system based on daily sample analyses would be provided to regulate the concentration of dissolved solids in the circulating water. The cooling tower basins would have a sloping bottom to facilitate the collection and periodic purging of accumulated solids.

2.2.3.7 Closed Cooling Water System and Auxiliary Cooling Tower

Key plant equipment would require cooling during operation. A separate closed cooling system would circulate water to provide cooling for bearings, lube oil coolers, generator air coolers, and other components. The closed cooling system water would be cooled by the auxiliary cooling tower. This system would be in operation at all times. An auxiliary cooling tower is required because operation of the main tower would vary with ambient temperature and would shut down during periods of cooler temperature.

2.2.3.8 Plant Water Supply System

During operation, the PGF would require a maximum 1,100 acre feet of raw water supply per year. Raw water would be supplied from a groundwater well and by lease from the adjacent landowner (see Section 2.2.4, Water Supply, for a discussion of raw water supply and availability). The raw water would be stored in two raw water storage tanks, each of which would hold 2 million gallons and would be approximately 24.5 feet high. One tank would be used as a raw water supply tank for plant operations, the other would store fire water. The raw water pumps would provide makeup water to the cooling tower and supply feedwater to the water treatment plant.

2.2.3.8.1 Demineralized Water System

Water used in the stream cycle must be highly purified. Impurities in the raw water would be removed by the demineralizer system to provide high purity makeup water for the HRSG. The demineralizer system would have four main components: (1) filtration, (2) membrane degasification, (3) reverse osmosis, and (4) ion exchange demineralization. Incoming raw water would be filtered in two stages, first by back-washable multimedia filters, and then with 5-micron disposable cartridge filters. The multimedia filter would be cleaned periodically by backwashing with filtered water. The backwash water would be discharged to the cooling tower.

The filtered water would then be degasified by one of two identical membrane degasification units. This system uses small quantities of dilute sulfuric acid or sodium hydroxide for pH control and a low flow of nitrogen gas to remove carbon dioxide and dissolved oxygen.

The degassed water would then be fed to one of two double pass reverse osmosis units, which would remove over 99 percent of the dissolved solids. The water would pass through two reverse osmosis membranes, with the reject water from the first membrane being recycled into the cooling tower. The reject water from the second membrane would be recycled into the feed water for the first membrane. Product water from the double pass reverse osmosis would be stored in the reverse osmosis water storage tank. Water from the reverse osmosis tank would be pumped through a series of mixed bed ion exchange vessels, which would be regenerated by a vendor offsite. The final product water would be stored in the demineralized water storage tank and drawn as required for HRSG makeup.

All water treatment equipment except for large tanks would be contained inside the water treatment building, a structure approximately 20 feet high. Water entering the floor drain system would be discharged to the cooling tower, or to the wastewater storage pond when the cooling tower is not in operation.

2.2.3.8.2 Condensate and Feedwater System

The condensate and feedwater system would consist of pumps, pipes, and vessels that would collect the condensed steam turbine exhaust and deliver it to the HRSG to be converted to high-pressure steam. The steam turbine exhaust steam would be condensed in the condensing systems and collected in the hotwell. Condensate pumps would move the condensate through several heat exchangers and deliver it to the deaerator. Feedwater makeup from the demineralized water storage tank would replace water and steam lost from the cycle. Steam would be added to the deaerator to heat the water and remove dissolved oxygen and other gases. The boiler feed pumps would take water from the deaerator and deliver boiler feedwater at the appropriate pressure to the various sections of the HRSG.

2.2.3.9 Wastewater Disposal

Operation of the PGF would produce the following four types of wastewater:

- Wet cooling tower blowdown
- Miscellaneous equipment drains and maintenance discharges
- Sanitary waste
- Stormwater

Each of these wastewater streams is described in the following subsections.

2.2.3.9.1 Cooling Tower Blowdown

During operation of the wet tower, a portion of the circulated water would be evaporated, thus removing heat from the cooling water, a process that would concentrate the minerals in the circulating water. While evaporated water would continuously be replaced by adding “makeup water,” this process would not sufficiently dilute the concentrated minerals. To reduce mineral concentration, a portion of the circulating water with its concentrated minerals is removed as blowdown. Since the makeup water added to the system would be much lower in mineral concentration than the blowdown water removed from the system, an appropriate concentration balance can be maintained.

Water use would vary with ambient temperature, with the highest flows on hot summer days and lower flows on cold winter days. Cooling tower makeup would consist of well water stored in the raw water tank. The cooling tower makeup water supply system is conservatively based on 5 cycles of concentration[6] in the cooling tower. It is expected that the cooling tower would be operated between five and ten cycles of concentration, as determined by water chemistry. Blowdown removes the concentrated impurities that collect in the cooling tower, and the blowdown water is classified as wastewater. This wastewater would then be pumped to the wastewater storage pond.

The 10-acre wastewater storage pond would have the capacity to store up to 70.3 acre-feet of cooling tower blowdown. A discharge pipeline from the wastewater pond would be interconnected to the field irrigation system of Plymouth Farm, the adjacent property. Plymouth Farm would withdraw water stored in the pond and blend it with the farm's water supply for crop

[6] Cycles of concentration = number of times (cycles) cooling water is concentrated by evaporation in the cooling tower.

irrigation. The PGF would enter into a long-term contract with Plymouth Farm for disposal of the plant's cooling tower blowdown.

As part of the agreement with Plymouth Farm, the PGF would obtain an Industrial Waste Water Discharge Permit from the Washington State Department of Ecology (Ecology). This permit would set the standards for maximum levels of concentrations that can be applied as irrigation water. To meet these standards, wastewater from the storage pond would be blended with available irrigation water from the farm, and the blended water would be applied to crops on the farm.

Cooling tower blowdown generated during non-irrigation months would be stored in the wastewater storage pond. During irrigation months, water from the wastewater pond and water discharged directly from the cooling tower would be combined and discharged through the irrigation system.

The disposal of cooling tower blowdown as irrigation water is described in more detail in Section 2.2.6 Wastewater and in Appendix A.

2.2.3.9.2 Miscellaneous Wastewater

During normal operation of boiler blowdown, demineralized water treatment system discharges and similar wastewater would be discharged to the cooling tower basin and used as cooling tower makeup. These discharges may be diverted to the wastewater system if the cooling tower does not require makeup or is incapable of accepting the water.

2.2.3.9.3 Sanitary Waste

Sewage and other sanitary wastewater would be discharged to a septic tank system. Sanitary wastes generated at the plant site would come from toilet and lunchroom facilities provided for plant operation personnel in the administration building. Sanitary wastes would be discharged into a small onsite pressure distribution-type septic system. The septic system would be permitted under the jurisdiction of the Benton-Franklin Health Department and would be installed in accordance with its requirements. Discharge flowrate to the system is estimated to be less than 500 gallons per day; however, the system would be designed for a minimum of 500 gallons per day.

The system would include a 1,000-gallon precast concrete septic tank, pump chamber, and associated disposal field. The septic tank and pump chamber would be located on the west side of the administration building. The disposal field would be located in the open area just north of the wet cooling towers. The soil at the site is generally characterized as Type III loamy sands (see Section 3.1 for further discussion of site soil characteristics). Maximum application rate for this type of soil is 0.727 gallons per day per square foot. The required area of disposal field is about 690 square feet. Three 80-foot, perforated pipe distribution laterals in 3-foot-wide trenches 10 feet apart would be provided.

2.2.3.9.4 Stormwater

The portion of the plant site that contains structures and equipment would include a stormwater collection system, which would collect stormwater runoff from paved areas, building roofs, and other impervious surfaces and direct these flows to a stormwater system. The stormwater runoff would be collected, pass through an oil/water separator, and then flow to the onsite stormwater pond (see Figure 2-4 for the location of this pond on the plant site). The stormwater would evaporate, leach into the ground, or be directed through a biofiltration swale to surface runoff. The stormwater pond area of 1 acre in surface area is included in the initial site configuration. During final plant design, the pond area and shape would be confirmed so that final design is based on a maximum 50-year storm event. It is expected that the final pond size would be smaller than 1 acre.

2.2.3.10 Natural Gas Fuel System

The combustion turbine would be fueled by natural gas. A fuel gas system would supply the natural gas at suitable pressure and temperature to the combustion turbine and any other miscellaneous uses such as unit heaters. Fuel would be delivered at high pressure from the Williams Co. compressor station. Additional discussion on the natural gas fuel system is provided in Section 2.2.5, Fuel Supply.

2.2.3.11 Plant Operating/Safety Systems

Several key support systems would be required to operate the PGF, including the unit control, instrument air, and fire protection systems. These systems are described as follows:

- **Unit Control –** The facility control system would incorporate a distributed control system (DCS) for automatic and remote manual control by an operator. The DCS would be an on-line, real-time system that provides automatic operation, control, monitoring and data trending and logging of the plant systems from the main control room. The DCS control systems would be located in a separate, centrally located main control room in the turbine building. The control room would also house the controls for the common systems such as fire protection, circulating water, and cooling towers. It would also house the site security, continuous emission monitoring equipment, plant computers, and other similar equipment. The control room would be staffed at all times.

- **Instrument Air/Service Air Systems –** Two air compressors, each with 100 percent capacity, would be provided to supply instrument air to the facility. The air compressors would include after cooler and inlet filters. An air receiver would be located downstream of the air compressors. Two air dryers (one operating and one spare) would be supplied with prefilters and afterfilters and would be designed to dry the compressed air to a dewpoint of 40°F below zero.

- **Fire Protection System –** The entire site would be protected by a fire protection system, which would consist of two parallel fire pumps taking water from the 2 million-gallon fire water storage tank. One fire pump would be driven by an electric motor, and the other by a diesel engine that would start automatically if there were a demand for fire water upon loss of electric power. The fire pumps would supply the fire system, which would loop around the plant site. The fire loop would include fire hydrants, sprinkled building spaces, cooling tower spray nozzles, and deluge systems at oil reservoirs and the main power transformers in the substation. A small, motor-driven jockey fire pump would keep the fire loop pressurized at all times.

2.2.3.12 Plant Electrical Systems

2.2.3.12.1 Electrical Substation

The output of the electrical generators would be connected to the PGF's electrical substation (see Figure 2-4 for location). The PGF substation would contain two step-up transformers, one for each generator, to raise the generated voltage (18 kV) to transmission voltage (230-kV or 500-kV; see Section 2.3 for further discussion). The substation would include required power circuit breakers, disconnect switches, instrument transformers, surge arresters, insulators, a control building, protective relaying, and metering. The substation would use rigid, tubular aluminum buswork complete with aeolian vibration damping cable, expansion joints, and fittings set on 20-foot, phase-to-phase spacing.

Equipment, buswork, and structures would be designed to withstand the large forces created by the available fault current conditions. All equipment and buswork would be designed and installed to limit the effects of corona by including corona shields and rings as needed.

The dead-end towers, rigid bus supports, and equipment supports would be steel. High voltage (230-kV or 500-kV) substation structures would be arranged to include adequate space for maintenance and replacement of large equipment such as transformers and power circuit breakers.

Direct stroke lightning protection would be provided by the use of overhead shield wires and lightning masts connected to the substation ground grid. Overhead shield wires would be high-strength steel wires arranged to provide shield zones of protection.

The substation control building would be sized to accommodate the relay and control panels, communication equipment, metering panels, direct current (DC) battery systems, low-voltage alternating current (AC) systems, and cableways. Protective relaying would be provided as required for the interconnection to protect all equipment and the transmission lines terminating in the substation. The protective relaying along with the circuit breakers would detect and then isolate faulted equipment so as to minimize outages and damage.

While the PGF power plant is not in operation, maintenance and standby power would be provided by Benton REA. A Benton REA substation serves the adjacent Williams Co. facility and a Columbia River water pumping station west of the site. All transformers, switching, and other electrical equipment would be installed inside a fenced substation.

Startup power for the plant would be provided by the BPA transmission system. The combustion turbine generator would be operated as a motor to accelerate the combustion turbine to operating speed. The turbine would then be fired, and the generator would commence providing power to the transmission system.

2.2.3.12.2 Auxiliary AC Power Loads

An auxiliary transformer in the substation would provide maintenance power from the Benton REA system. The connected auxiliary power loads would be approximately 5 MW. A small diesel generator would supply critical AC loads during emergency situations.

2.2.3.12.3 125-Volt DC System

A 125-volt DC battery distribution system would be provided to supply power to critical equipment and protective devices, such as the turbine generator bearing and shaft seal oil generator pumps, protective relaying schemes, breaker controls, the vital AC inverter, annunciation, and various other control circuits, for a minimum of 8 hours following a complete loss of normal AC power.

The DC system consists of one battery, two chargers (one operating, one standby), a distribution switchboard, and a distribution panelboard.

2.2.3.12.4 Uninterruptible Power Supplies

Uninterruptible power supplies (UPS) would be provided for loads for which the loss of supply power would immediately affect unit operations. The UPS system would consist of a 125-V-DC-to-120-V-AC inverter supplied from the station battery. A make-before-break static transfer switch (with manual bypass) is connected to the inverter output and the instrument AC distribution panel, and a vital AC distribution panel.

The inverter output would be the normal source to the vital AC loads. Upon inverter malfunction or manual initiation, the loads would be automatically transferred to the instrument AC source and require manual retransfer. The inverter would be equipped so as to be synchronous with the phase-lock to the AC bypass source.

2.2.4 WATER SUPPLY

Overall water supply requirements are a maximum of 1,100 acre feet per year (af/yr) and a maximum flow rate of 673 gallons per minute (gpm). Final water supply requirements would be determined during final design but would not exceed 1,100 af/yr.

Water would be supplied to the PGF from two existing water supplies:

- **PGF 960 af/yr –** This supply would originate from a well located on the Plymouth Farm adjacent to Christy Road. The water rights associated with this well would be transferred to the PGF. An application to transfer this right has been reviewed by the Benton County Water Conservancy Board, which has forwarded its Record of Decision (ROD) for approval to the Washington State Department of Ecology (Ecology). Ecology will give final approval to the water right transfer.

- **Plymouth Farm 140 af/yr –** This supply would be leased by Plymouth Farm to the PGF and would be supplied from the existing farm water supply. Plymouth Farm maintains